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**BEFORE THE IDAHO PUBLIC UTILITES COMMISSION**

| | | |
|---|---|---|
| IN THE MATTER OF THE APPLICATION OF INTERMOUNTAIN GAS COMPANY FOR THE AUTHORITY TO CHANGE ITS RATES AND CHARGES FOR NATURAL GAS SERVICE TO NATURAL GAS CUSTOMERS IN THE STATE OF IDAHO | ) | Case No. INT-G-16-02 |

# DIRECT TESTIMONY OF LORI A. BLATTNER

## FOR INTERMOUNTAIN GAS COMPANY

August 12, 2016

## I. INTRODUCTION

**Q. Please state your name, title and business address.**

A. My name is Lori A. Blattner. I am a Regulatory Analyst with Intermountain Gas Company ("Intermountain" or "Company"). My business address is 555 South Cole Road, Boise, ID 83707.

**Q. Ms. Blattner, would you please summarize your educational and professional experience.**

A. I graduated from University of Idaho in 1993 with a Bachelors degree in Agricultural Economics. I joined Intermountain Gas in 1997. During my time in the Regulatory Department, I have attended several ratemaking classes, including a Threshold Associates cost allocation training, Navigant Consulting cost of service workshop, and an SGA Ratemaking seminar. Throughout my career at Intermountain, I have been responsible for cost of service and rate making. I have also been involved at a high level in integrated resource planning, developing the annual purchased gas cost adjustment, weather normalization and forecasting.

**Q. Have you previously testified before this Commission?**

A. No.

**Q. What is the purpose of your testimony?**

A. My testimony covers three areas. First, I will discuss and support the weather normalization process used to develop the test period billing determinants. Second, I will discuss the allocated class cost of service study prepared for this case. Third I will discuss and explain the rate design changes that are being proposed in this proceeding.

**Q. Are you sponsoring any exhibits with your testimony?**

A. Yes, I am sponsoring the following exhibits:

| | |
|---|---|
| Ex. 18 | Weather Normalization Opinion |
| Ex. 19 | Minimum System Study Results |
| Ex. 20 | Class Cost of Service Summary Results |
| Ex. 21 | Class Cost of Service Results – Account Detail |
| Ex. 22 | Class Cost of Service Account Inputs |
| Ex. 23 | Class Cost of Service Allocation Factors |
| Ex. 24 | Rate Design Calculations |

## II. WEATHER NORMALIZATION

**Q. Is Intermountain proposing an adjustment to reflect normal weather?**

A. Yes.

**Q. Why is an adjustment to gas utility revenues and volumes to normalize weather appropriate?**

A. Temperature is the primary driver of variances in natural gas usage, and the Company's rates include charges that are based on consumption. Since these charges are dependent on consumption, variations in weather will affect the amount of revenue received by the Company. For example, a year with lower consumption due to warmer than normal temperatures will result in lower revenues for the Company. Conversely higher consumption due to colder than normal temperatures will result in higher revenues for the Company. The Company's proposed DSM programs will also result in incrementally lower usage per customer.

Weather Normalization is the term used to describe the process by which usage levels are adjusted to the level they would have been under normal weather conditions and from which normalized (pro forma) revenues can be determined.

**Q. Would you please describe the weather normalization process?**

A. Yes. To determine the degree to which actual gas sales were higher or lower than normal as a result of actual weather, it is necessary to first quantify the relationship between weather and sales. This quantification is achieved through the use of multiple regression analysis. The company developed regression equations based on eleven years of data: one that describes RS-1 sales; another that describes RS-2 sales; and one that describes small commercial sales (GS-1).

**Q. What are HDD's?**

A. HDD's, or heating degree days, are units used to relate a day's temperature to the energy demands of temperature sensitive load, primarily for space heating. HDD's are calculated by subtracting a day's average temperature from a reference temperature, in this case 65° Fahrenheit.

**Q. Please continue with your explanation of the weather normalization process.**

A. Once the regression equations have been specified and estimated, it is the coefficients of the weather variables that are of primary importance to the weather adjustment process. These coefficients measure the response of sales to changes in the weather. For example, the coefficient of HDD65 in the residential equation represents the change in the number of therms per customer that a change in one HDD65 would cause. By multiplying this coefficient by the difference between the normal number of heating degree days for a particular month and the number

that actually occurred, the difference between actual and normal therms per customer is determined.

**Q. What data did you use to determine the normal heating degree days?**

A. Normal heating degree days are based on a rolling 30-year average of heating degree days reported each month by the National Weather Service. The IGC service area contains regions with different weather patterns. To incorporate these different weather patterns normal weather was constructed using customer class weighted weather data from the Boise, Caldwell, Twin Falls, Sun Valley, Pocatello, Rexburg, and Idaho Falls weather stations. Each year, normal is recalculated to include the most recent year and drop off the oldest year, thereby reflecting the most recent information available. The normal weather used in this weather normalization process includes the 30 year period 1986 through 2015.

**Q. Is your proposed weather adjustment process consistent with sound statistical practices and the methodology approved in the Company's Weather Normalization Case?**

A. Yes, the methodology has been reviewed by two experts in statistics and forecasting, Professors Fry and Shannon from Boise State University. In their opinion, attached as Exhibit 18, "the methods used by Intermountain Gas Company are an appropriate and adequate basis for weather normalization". They go on to state that Intermountain's approach follows the methodology approved by the Idaho Public Utilities Commission in Case U-1034-134.

**Q. What are the results of the weather normalization process?**

A. The test year in this proceeding is the twelve months ending December 31, 2016, and consists of six months of actual data, January through June of 2016, and six months of forecasted data. The six months of actual data has been weather normalized as discussed above. The results of the weather normalization are summarized in Table B.1 below.

**Table B.1: Weather Normalization Results**

| Rate Class | Actual HDD | Normal HDD | Actual Therms | Normal Therms | Difference Therms |
|---|---|---|---|---|---|
| R-1 | 4,003.2 | 3,985.6 | 22,722,002 | 22,660,127 | (61,875) |
| R-2 | 3,891.0 | 3,931.4 | 118,984,790 | 119,838,399 | 853,609 |
| GS-1 | 4,076.1 | 4,034.9 | 71,988,101 | 71,008,852 | (979,249) |
| Total | | | | | (187,515) |

The actual and normal degree days vary for each of the rate classes due to the weather station weighting process described above. Overall, the weather normalization adjustment results in a reduction in usage of 187,515 therms. There is a corresponding revenue adjustment as explained by Company witness Darrington.

## III. ALLOCATED CLASS COST OF SERVICE STUDY

**Q. What is an Allocated Class Cost of Service Study ("ACOSS")?**

A. An ACOSS is an analysis of costs that assigns to each customer or rate class its proportionate share of the utility's total cost of service, i.e., the utility's total revenue requirement. The results of these studies can be utilized to determine the relative cost of service for each customer class and to help determine the individual class revenue responsibility.

**Q. What is the purpose of an ACOSS?**

A. The purpose of an ACOSS is to determine what costs are incurred to serve the various classes of customers of the utility. When these costs are all tabulated, the rate of return that is provided by each class of service of the utility can be determined. The ACOSS is a tool used to assist in determining revenue responsibility by rate class and rate design. The results of the ACOSS will provide the analyst with the data necessary to design cost-based rates.

**Q. What is the guiding principal that should be followed when preparing an ACOSS?**

A. Cost causation is the fundamental principle applicable to all cost studies for purposes of allocating costs to customer groups. Cost causation addresses the question; which customer or group of customers causes the utility to incur particular types of costs? In order to answer this question, it is necessary to establish a relationship between a utility's customers and the particular costs incurred by the utility in serving those customers.

**Q. What are the steps to performing ACOSS?**

A. In order to establish the cost responsibility of each customer class, initially a three step analysis of the utility's total operating costs must be undertaken. The three steps which are the predicate for an ACOSS are: (1) cost functionalization; (2) cost classification; and (3) cost allocation of all the costs of the utility's system.

**Q. Please describe cost functionalization.**

A. The first step, cost functionalization, identifies and separates plant and expenses into specific categories based on the various characteristics of utility operation. Intermountain's functional cost categories associated with gas service include:

Storage, Transmission, and Distribution. In addition, the ACOSS includes a function for the cost of gas in order to separately track gas costs from base rate costs. Gas costs are addressed in the Company's annual Purchased Gas Cost Adjustment filing (PGA) and are not part of this proceeding.

**Q. Please describe cost classification.**

A. Classification of costs, the second step, further separates the functionalized plant and expenses into the three cost defining characteristics of: (1) customer related; (2) demand or capacity related; and (3) commodity related.

Customer costs are incurred to extend service to and attach a customer to the distribution system, meter any gas usage and maintain the customer's account. Customer costs are largely a function of the number and density of customers served, and continue to be incurred whether or not the customer uses any gas. They may include capital costs associated with minimum size distribution mains, services, meters, regulators and customer billing and accounting expenses.

Demand costs are capacity related costs associated with a plant that is designed, installed and operated to meet maximum hourly or daily gas flow requirements, such as transmission and distribution mains or more localized distribution facilities which are designed to satisfy individual customer maximum demands.

Commodity costs are those costs that vary with the throughput sold to, or transported for, customers.

**Q. Please describe cost allocation.**

A. The final step is the allocation of each functionalized and classified cost element to the individual customer or rate class. Costs are directly assigned or are allocated on customer, demand, commodity and internal allocation factors.

Direct assigned relates to the specific identification and isolation of plant and/or expenses that are incurred to serve a specific customer or group of customers. Direct assignments are based on analyses of detailed data that directly links costs to a rate class, or to a subset of customers in a rate class. Direct assignment of costs is the preferred allocation approach because no allocation is required to determine the costs of serving customers in each class. However, it is not realistic to assume that a large portion of the Company's plant and expenses can be directly assigned as the majority of the costs are joint use facilities.

Customer, demand and commodity external allocation factors such as the number of customers, peak day usage, and annual usage are developed from the Company's records. Internal allocation factors are developed within the ACOSS from previously allocated costs, such as plant or labor costs.

**Q. How have the demand-related costs been allocated in the ACOSS?**

A. Demand costs have been primarily allocated using a coincident peak demand methodology. As described by Company Witness Gilchrist, Intermountain's system has been designed and built to meet the peak demands of the customers, therefore allocating the demand costs on the basis of peak day utilization is in keeping with the cost causation principle. The coincident peak day used to develop the allocation factor is the Company's most recent peak day which occurred January 1, 2016.

**Q. How was distribution mains plant account, Account 376, classified and allocated in the ACOSS?**

A. A portion of the distribution mains account was classified as customer and the remaining costs were classified as demand. Identifying a portion of mains investment as customer related is an accepted principle throughout the gas industry. The assumption is that distribution mains (FERC Account No. 376) are installed to meet both system peak load requirements and to connect customers to the utility's gas system. Therefore, to ensure that the rate classes that cause the investment in this plant are charged with its cost, distribution mains should be allocated to the rate classes in proportion to their peak period load requirements and numbers of customers.

**Q. What are the factors that affect the level of distribution mains facilities installed by a utility?**

A. There are two cost factors that influence the level of distribution mains facilities installed by a utility in expanding its gas distribution system. First, the size of the distribution main (i.e., the diameter of the main) is directly influenced by the sum of the peak period gas demands placed on the utility's gas system by its customers. Secondly, the total installed footage of distribution mains is influenced by the need to expand the distribution system grid to connect new customers to the system. Therefore, to recognize that these two cost factors influence the level of investment in distribution mains, it is appropriate to allocate such investment based on both peak period demands and the number of customers served by the utility.

**Q. How is the customer component of distribution mains determined?**

A. The two most commonly used methods for determining the customer cost component of distribution mains facilities are: (1) the zero-intercept approach; and (2) the most commonly installed, minimum-sized unit of plant investment approach.

Under the zero-intercept approach, which is the method utilized in Intermountain's ACOSS, a customer cost component is developed through regression analyses to determine the unit cost associated with a zero inch diameter distribution main. The method regresses unit costs associated with the various sized distribution mains installed on the utility's gas system against the actual size (diameter) of the various distribution mains installed. The zero-intercept method seeks to identify that portion of plant representing the smallest size pipe required merely to connect any customer to the utility's distribution system, regardless of the customer's peak or annual gas consumption.

The most commonly installed, minimum-sized unit approach is intended to reflect the engineering considerations associated with installing distribution mains to serve gas customers. This method utilizes actual installed investment units to determine the minimum distribution system rather than a statistical analysis based upon investment characteristics of the entire distribution system. While the zero-intercept method, with reliable data, estimates the customer costs associated with a zero-size pipe diameter, the minimum-size method may include some capacity costs since any minimum size pipe considered will, in fact, be capable of actually delivering some gas.

**Q. Please discuss how the zero-intercept study was performed and its results.**

A. The results of the zero-intercept study are shown in Exhibit 19. The Company's plant accounting records provided the installed cost, footage, type (plastic, steel), size (diameter) and vintage (date of installation) for the distribution mains. The vintage installed costs were translated to a common current cost using the Handy-Whitman Index ("HWI"). The HWI calculates cost trends for different types of utility construction with separate indices for gas, electric and water industries. Using the HWI adjusted costs, an installed cost per foot was calculated for each pipe size and type and a regression analysis of the unit costs and pipe size was performed for both steel and plastic pipe types. The results of the regression analysis can be expressed formulaically as:

$$y = mx + b$$

Where: y = average cost per installed foot of Intermountain's distribution mains

m = cost per installed foot per inch of pipe diameter

x = diameter of distribution mains

b = cost per installed foot

The regression analysis shows that regardless of the diameter of the main, the average cost of a distribution main in Intermountain's system will be at least equal to $8.55 per installed foot. This per foot cost component is related to the process of extending the distribution mains to connect customers, which is a function of the length of the main and not the size of

the main, and represents the customer cost component of distribution mains.

**Q. How were the results of the zero-intercept study used in the ACOSS?**

A. As shown in Exhibit 19, the customer cost unit rate for both steel and plastic type pipe was applied to the total distribution mains footage for each pipe type to determine the total customer costs. This total customer cost was divided by the total HWI adjusted cost of distribution mains to provide the customer cost percentage of 47.16%. This percentage was used in the ACOSS to apportion the historical installed costs of distribution mains to the customer component and allocated to the rate classes on a customer factor. The remaining distribution mains costs were classified as demand and allocated on the peak day factor.

**Q. How were the other distribution plant accounts classified in the ACOSS?**

A. Plant accounts 380 through 385 are classified as customer related. These accounts include costs related to services, meters, meter installations, and regulators. Plant accounts 375, Structures and Improvements, and 378, Measuring and Regulation, are classified as demand. Account 374, Land and Land Rights, was allocated on an internal factor based on structures, mains, and services and therefore has costs classified as both demand and customer.

**Q. How were the distribution plant accounts allocated to the rate classes?**

A. As noted above the demand component of distribution mains is allocated on the peak day factor. The other two demand related distribution plant accounts were allocated using a peak and average methodology. Accounts 375, Distribution Structures and Improvements, and 378, Distribution Measuring and Regulation

Equipment, contain costs related to both peak and annual usage both of which are included in the calculation of the peak and average allocation factor.

The services, meters, meter installation and house regulator accounts were allocated on weighted customer basis. The weighting factor was based on a study of the costs of meters for each rate class. Account 385, Industrial Regulation, was allocated on a weighted customer basis excluding the residential classes.

**Q. How were the storage plant accounts treated in the ACOSS?**

A. The storage plant accounts contain the costs related to the Company's LNG facilities. As discussed by Company Witness Gilchrist these facilities are needed to provide deliverability and reliability during peak periods. Therefore, the storage plant accounts are classified as demand and allocated on a peak day basis.

**Q. How were the transmission plant accounts treated in the ACOSS?**

A. The transmission plant accounts contain the costs related to the Company's high pressure transmission facilities. As discussed by Company Witness Gilchrist these facilities were designed and sized to provide deliverability during peak periods. Therefore, the transmission plant accounts are classified as demand and allocated on a peak day basis.

**Q. How were the general and intangible plant accounts treated in the ACOSS?**

A. The general and intangible plant accounts were allocated on an internal factor based on the allocations of storage, transmission and distribution plant.

**Q. Please describe the method used to allocate the accumulated depreciation reserve and depreciation expenses.**

A. The accumulated reserve and depreciation expense were allocated on internal factors based on the allocation of the associated plant.

**Q. Please describe the method used to allocate the storage, transmission and distribution Operations and Maintenance ("O&M") expense?**

A. In general, these expenses were allocated on the basis of the cost allocation methods used for the Company's corresponding plant accounts. A utility's O&M expenses generally are thought to support the utility's corresponding plant in service accounts. As a result, the allocation basis used to allocate a particular plant account will be the same basis as used to allocate the corresponding expense account.

**Q. How were the customer accounting expenses, accounts 902 – 904, treated in the ACOSS?**

A. Meter reading expense, account 902, is allocated on the basis of the number of customers. Customer records and collection expense, account 903, is allocated on a weighted customer basis based on meter costs. Account 904, uncollectible expense, is allocated to the residential and general service classes based on an analysis of account write-offs.

**Q. How were customer service and sales expenses treated in the ACOSS?**

A. Customer service expenses, accounts 907 and-908, are allocated on a customer basis. Sales expenses, accounts 910 – 913, are allocated to the residential and general service classes on a peak day throughput basis.

**Q. Please describe the treatment of Administrative and General ("A&G") costs in the ACOSS.**

A. Accounts 923 and 924, outside services and property insurance, are plant related and allocated on an internal factor consisting of allocated storage, transmission and distribution plant. Accounts 925 and 926, injuries and damage and employee pensions and benefits, are labor related costs and are allocated on an internal labor factor. Rents and general plant maintenance expenses, accounts 931 and 932, are allocated on total plant basis and the remaining A&G expenses are allocated on an internal factor comprised of O&M expenses excluding A&G.

**Q. How were taxes other than income taxes treated in the ACOSS?**

A. Taxes other than income were allocated on a plant or labor basis depending on the nature of the tax. For example, payroll taxes were allocated on a labor basis while property taxes were allocated on the basis of plant.

**Q. How were income taxes allocated to each customer class?**

A. Income taxes are calculated for each rate class based on the pre-tax net income for the class.

**Q. What rate classes were included in the ACOSS?**

A. In this proceeding Intermountain is proposing to restructure some of its existing rate classes and the revised rate classes are those used in the ACOSS. Currently Intermountain has two residential rate classes with the primary difference between the classes being the presence of gas water heating. Intermountain is proposing to combine these two rate classes into a single residential rate class. Intermountain is also proposing to combine its two industrial customer transportation rate classes, T4 and T5, into a single rate class.

**Q. Why are these classes being restructured?**

A. As more fully explained below, Rate Schedules RS-1 and RS-2 are being combined because there is no justification for having different rate classifications for customers based on whether they use gas for space heating or water heating in addition to space heating.

With the addition of a demand charge to the T-4 customer class, the T-4 and T-5 classes are essentially the same type of service. Therefore, they are being combined into a single class of service.

**Q. Please describe the results of the ACOSS?**

A. The results of the ACOSS are shown on Exhibit 20. Page 1 of this exhibit provides a summary of the rate base, revenues, expenses and returns at current rates by class. As shown on line 17, the residential class is slightly below the system average return while the Large Volume Sales (LV-1) and Firm Transport Service class (T-4) show returns well above the system average. The General Service class (GS) shows a return significantly below the system average. The Interruptible Transport Service (T-3) exhibits a return well above the system average which is to be expected as this class is not allocated any peak demand related costs.

**Q. Does the ACOSS show the class revenue requirements at equal rates of return?**

A. Yes. Exhibit 20, Page 2, provides the results by class at equal rates of return. Line 10 of this exhibit shows the level of the revenue deficiency or surplus necessary to move the class to the system average return. Line 12 of this exhibit shows the revenue increase or decrease proposed for each rate class and line 20

shows the propose return for each class at the proposed rates. This information is summarized in Table 2 below:

**TABLE B.2 – Summary of ACOSS Results**

| Rate Class | Return @ Current Rates | Revenue (Deficiency)/Surplus @ Equal Return | Proposed Increase | Return @ Proposed Rates |
|---|---|---|---|---|
| **Residential** | 4.41% | ($7,775,305) | $7,755,305 | 7.42% |
| **General Service** | 2.21% | ($4,466,759) | $4,466,759 | 7.42% |
| **Large Volume** | 23.38% | $141,850 | ($141,805) | 7.42% |
| **T3** | 143.99% | $528,042 | ($528,042) | 7.42% |
| **T4** | 11.45% | $1,386,472 | ($1,386,472) | 7.42% |
| | | | | |
| **Total** | 4.85% | ($10,165,700) | $10,165,700 | 7.42% |

**Q. Please explain the remaining pages of Exhibit 20 and Exhibits 21, 22 and 23.**

A. Exhibit 20, page 3 shows the rate base by function by class. Page 4 provides a functional cost of service, by class at equal rates of return and page 5 provides a functional and total unit cost analysis by class. The unit cost analysis provides support for the proposed customer and demand charges.

Exhibit 21 shows how each account is classified and allocated to the classes. Exhibit 22 shows how the amount of each account and how the account is functionalized, classified and allocated. Exhibit 23 provides all the external and internal allocation factors used in the study.

## IV. RATE DESIGN

### A. Introduction

**Q. Please explain the organization of your testimony concerning the Company's proposed changes to rate classes, rate structures, and rate design.**

A. In subsections B, C, D, and E of this Section IV of my testimony, I will describe and explain the Company's proposals related to rate schedules and rate structures as follows. Specifically, I will explain the Company's proposals to:

1. Eliminate the current rate schedules for residential heating service (Rate Schedule RS-1) and residential heating and hot water service (Rate Schedule RS-2) and create a single rate schedule for service to all residential customers (Rate Schedule RS);
2. Modify the Rate Schedule GS-1 rate structure so that the rates charged to the customers in this class more closely reflect the Company's costs to serve these customers, helping to reduce subsidization within the class;
3. Eliminate the seasonal rate structures by which residential and general service customers are charged higher rates in the summer than in the winter periods;
4. Combine the T-4 and T-5 rate schedules to create a single rate structure for the Company's Industrial firm transportation service customers (Rate Schedule T-4);
5. Modify the Rate Schedule LV-1 rate structure, by adding a demand charge, so that the customers in this class are charged for the distribution system capacity that is made available for their service;
6. Apply the current Rate Schedule T-5 rate structure, which includes a demand charge, to the proposed Rate Schedule T-4 rate structure,

In subsection F of this Section IV of my testimony, I will present and support the calculations and analysis that I performed to develop the Company's proposed rates.

**Q. In developing the rate design proposals that you describe and support in the following sections, were you guided by any principles and directives?**

A. Yes, I took into account (1) the findings and recommendations of Company Witness Terzic, in his testimony in this proceeding concerning customer charges and demand charges and (2) the principles of rate design that were developed by James C. Bonbright.

**Q. Please summarize Company Witness Terzic's findings and recommendations concerning customer charges and demand charges.**

A. Mr. Terzic explains that customer charges and demand charges are two types of fixed fees that are appropriate elements of sound rate design, because these charges do not vary based on the level of natural gas volumes flowing through the distribution system. Said another way, the Company's fixed costs to construct, operate and maintain the Company's distribution system should be largely recovered through fixed charges.

**Q. What are the Bonbright rate design directives?**

A. The industry has long accepted the principles of rate design first put forth by James C. Bonbright, [1] which are:

- Rate attributes: simplicity, understandability, public acceptability, and feasibility of application and interpretation;
- Effectiveness of yielding total revenue requirements;
- Revenue (and cash flow) stability from year to year;

[1] James C. Bonbright. Principles of Public Utility Rates (1st ed. 1961).

- Stability of rates themselves, minimal unexpected changes that are seriously adverse to existing customers;
- Fairness in apportioning cost of service among different consumers (rates based on cost causation);
- Avoidance of "undue discrimination"; and
- Efficiency, promoting efficient use of energy by the customer (e.g., such that utility's infrastructure and resources are not strained).

**B. Proposed Revisions to Current Residential Rate Classifications**

**Q. Please explain the Company's proposal to revise the residential rate classifications.**

A. Currently, the Company's Rate Schedule RS-1 is applicable to residential customers that use natural gas for space heating, and other purposes, but not for water heating, and Rate Schedule RS-2 is applicable to residential customers that use natural gas for both natural gas water heating and natural gas space heating, as well as other purposes. As I described in the introduction, the Company is proposing to eliminate the separate Rate Schedules RS-1 and RS-2 and to create a new Rate Schedule RS.

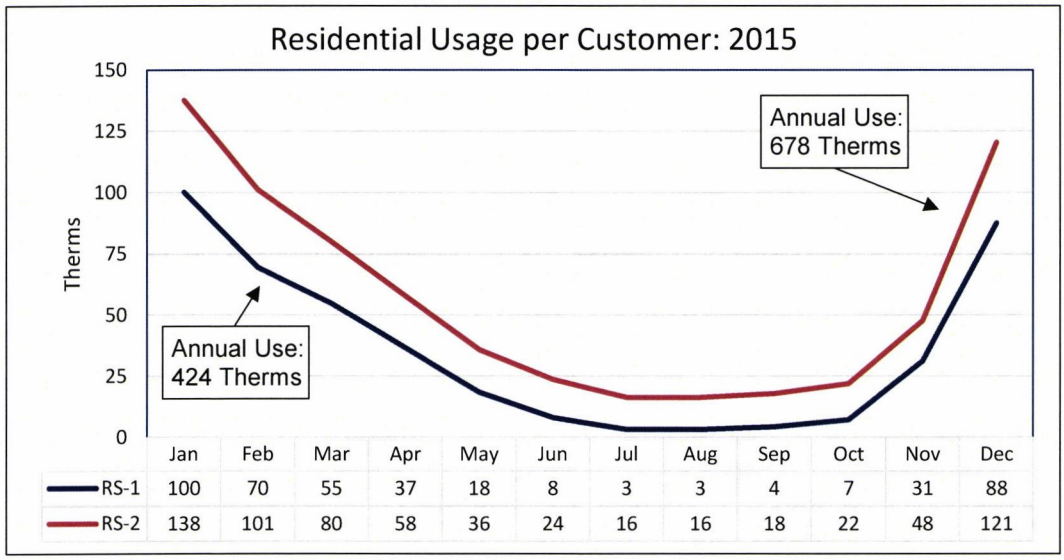
**Q. Please describe the current Rate Schedules RS-1 and RS-2.**

A. In 2015 the Company provided service to 66,783[2] RS-1 customers and 236,007[2] RS-2 Customers. Actual RS-1 2015 consumption was 30,711,979 therms and RS-2 consumption was 169,532,903. RS-1 customers paid an average cost of $0.90657 per therm for gas service, which was 16 percent greater than the average

[2] Customer numbers that support the revenue reported in Intermountain's 2015 FERC Form 2. .

cost of $0.78177 per therm that RS-2 customers paid for gas service. Table B.3 below shows the average monthly usage by RS-1 and RS-2 customers, and Table 4, below, shows the currently effective RS-1 and RS-2 rates.

**Table B.3 Residential Average Monthly Usage[3]**




| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| RS-1 | 100 | 70 | 55 | 37 | 18 | 8 | 3 | 3 | 4 | 7 | 31 | 88 |
| RS-2 | 138 | 101 | 80 | 58 | 36 | 24 | 16 | 16 | 18 | 22 | 48 | 121 |

**Table B.4 Residential Distribution Rates[4]**

| | RS-1 | RS-2 | Difference | % Difference |
|---|---|---|---|---|
| Customer Charge per month | | | | |
| Summer | $2.50 | $2.50 | $0.00 | 0.0% |
| Winter | $6.50 | $6.50 | $0.00 | 0.0% |
| Margin Charge per Therm[5] | | | | |
| Summer | $0.31617 | $0.19539 | $0.15199 | 38.20% |
| Winter | $0.20361 | $0.16176 | $0.07306 | 20.55% |

**Q. Please explain why the Company is proposing to eliminate the separate Rate Schedules RS-1 and RS-2 and to create a new Rate Schedule RS.**

A. The Company is proposing to eliminate the separate Rate Schedules RS-1 and RS-2 because Intermountain's cost drivers[6] for gas service to residential

3 The analysis summarized in Table 2X is derived from 2015 billing system data.
4 Fiftieth Revised Sheet No. 01, Fiftieth Revised Sheet No. 02. Effective July 1, 2016.
5 RS-1 Commodity Charges shown are net of Cost of Gas, $0.55589 per therm. RS-2 Commodity Charges are net of Cost of Gas, $0.51585 per Therm.

customers that use gas for space heating are not meaningfully different from the cost drivers for gas service to customers that use gas for water heating as well as space heating.

Further, there is certainly no cost justification for charging commodity rates to RS-2 customers that are lower than the RS-1 rates by 21 percent in the winter and 38 percent in the summer. It is not appropriate that, on an annual basis, average annual charges per therm to RS-2 customers are 16 percent less ($.0.12481 per therm) than average annual charges to RS-1 customers.

**Q. Are you aware of any gas distribution companies that have separate rate schedules for residential customers that use gas for (1) space heating and (2) hot water in addition to space heating?**

A. No, I am not. I reviewed the tariffs of Avista Idaho and gas distribution companies in surrounding states[7] and I determined that, other than Intermountain Gas, no gas distribution company has separate rate schedules for residential customers that use gas for space heating and for hot water in addition to space heating.

**C. Modifications to Rate Schedule GS-1**

**Q. Please describe the current Rate Schedules GS-1.**

A. According to the provisions of Rate Schedule GS-1, service is available at any point on the Company's distribution system to customers whose requirements for natural gas do not exceed 2,000 therms per day. In 2015 the Company provided

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6 These cost drivers are, generally, the allocators that are used in the ACOSS to allocate the balances in the Company's plant and expense accounts to each rate class.

7 I reviewed the tariffs of the following gas distribution companies: Avista Utilities (Idaho), MDU (Montana), Avista Utilities (Oregon), Cascade Natural Gas Corporation (Oregon), Cascade Natural Gas Corporation (Washington), Avista Utilities (Washington).

service to 31,738[8] GS-1 customers. Actual GS-1 consumption in 2015 was 103,111,511 therms and GS-1 customers paid an average cost of $0.71955 per therm for gas service. Table B.5, below, shows the currently effective GS-1 rates.

**Table B.5 General Service Distribution Rates[9]**

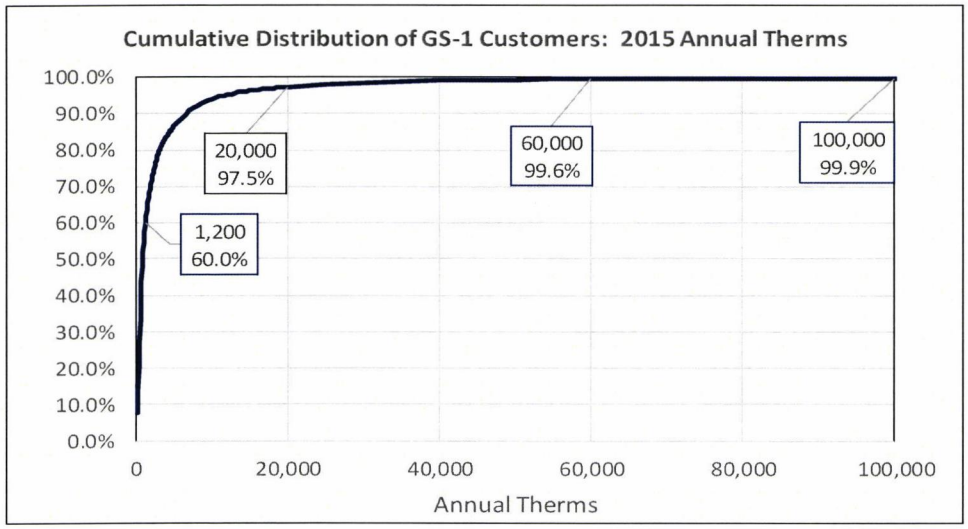
| | | | RS-1 | | |
|---|---|---|---|---|---|
| | | | Summer | Winter | |
| Customer Charge | | | $2.50 | $6.50 | per month |
| | | | | | |
| Commodity Charge per Therm[10] | | | | | |
| | Block 1 | 1st 200 Therms per bill | $0.21690 | $0.16605 | per Therm |
| | Block 2 | Next 1,800 Therms per Bill | $0.19517 | $0.14485 | per Therm |
| | Block 3 | Over 2,000 Therms per bill | $0.17415 | $0.12439 | per Therm |

The customers in Rate Schedule GS-1 are very diverse. Approximately 60 percent of GS-1 customers use less than 1,200 therms annually[11], which is comparable to the annual consumption of Residential RS-2 customers who use gas for space and hot water heating. At the other extreme, the largest 50 customers, which used at least 93,000 therms annually in 2015, represent 0.15 percent of total 2015 GS-1 customers, and 7.1 percent (6,834,601 therms) of total 2015 GS-1 annual consumption. This diversity of GS-1 annual consumption is demonstrated in Table 6 below, which shows the cumulative distribution of GS-1 customers, by annual consumption. Table B.6 demonstrates that Rate Schedule GS-1 includes a wide range of customers that are very different. At one extreme, 97.5 percent of the GS-1 customers consumed less than 20,000 therms in 2015; at

8 Customer numbers that support the revenue reported in Intermountain's 2015 FERC Form 2.
9 Fifty-Second Revised Sheet No. 03. Effective July 1, 2016.
10 GS-1 Commodity Charges shown are net of cost of gas of $0.51167 per therm.
11 Intermountain provided service to 31,738 GS-1 customers in 2015; 19,484 GS-1 customers (61.4 percent) used 1,200 therms or less. Total therm consumption by these customers was 9,323,339 therms, or 9.0 percent of total actual billing system GS-1 consumption.

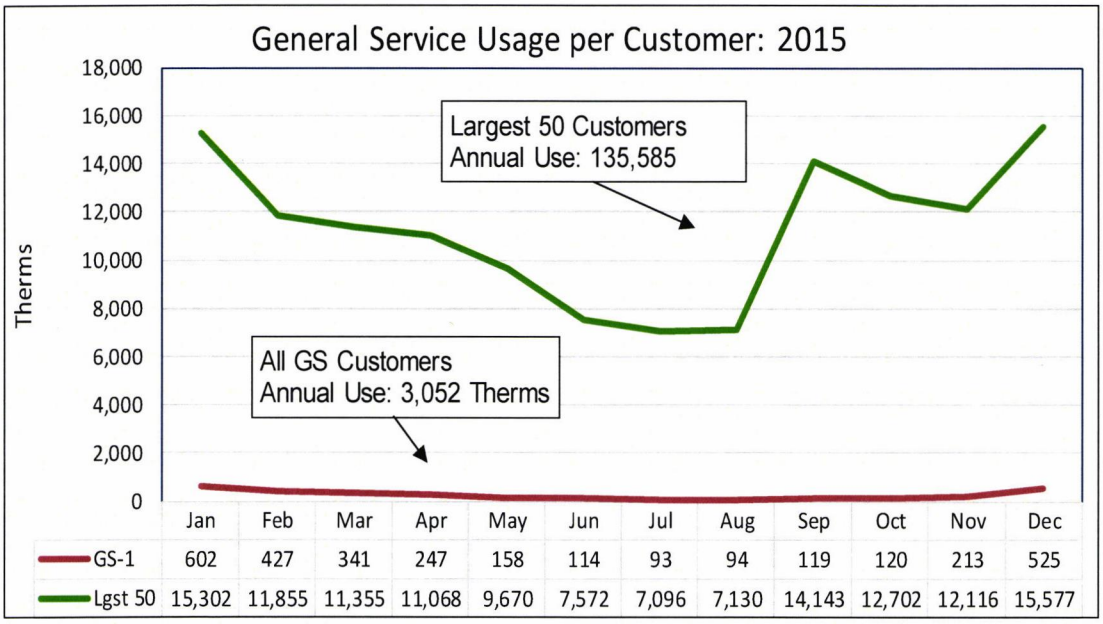
the other extreme, 0.2 percent of the GS-1 customers consumed at least 100,000 therms.

**Table B.6 GS-1 Annual Consumption Cumulative Distribution**




As another approach to demonstrate the diversity of GS-1 customers, Table B.7 below shows the average monthly usage by all GS-1 customers, and the 50 largest GS-1 customers.

**Table B.7 General Service Average Monthly Usage**




| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| GS-1 | 602 | 427 | 341 | 247 | 158 | 114 | 93 | 94 | 119 | 120 | 213 | 525 |
| Lgst 50 | 15,302 | 11,855 | 11,355 | 11,068 | 9,670 | 7,572 | 7,096 | 7,130 | 14,143 | 12,702 | 12,116 | 15,577 |

Based on this analysis of the GS-1 customers, the Company has determined that although the current GS-1 rate structure is a reasonable basis for charging most of the GS-1 customers, it is appropriate and necessary to make modifications to GS-1 rates and rate structures that would impact mostly the largest GS-1 customers, because the largest GS-1 customers are similar to many Industrial LV-1 customers, and very different from most GS-1 customers.

**Q. Please explain the Company's proposed modifications to the Rate Schedule GS-1 rate structure.**

A. The Company is proposing to add a fourth rate block to the GS-1 rate structure that would apply to a GS-1 customer's monthly consumption that exceeds 10,000 therms in a month. The company selected 10,000 for the fourth block to more reasonably reflect the cost to serve these largest GS-1 customers, which will therefore reduce the subsidization by the largest GS-1 customers of the smaller

GS-1 customers. This fourth block will also allow for better alignment between the rates charged to the largest GS-1 customers and the rates charged to the Company's LV-1 Large Volume Firm Sales Service customers.[12]

Customers that utilize the fourth block are typically small industrial type customers. Often, they are growing businesses that will eventually qualify for an industrial class. The fourth block rate will allow them to grow their business at a rate that is fair in comparison to similar type businesses that are larger in scale.

**Q. Please explain how adding the fourth block, for monthly consumption in excess of 10,000 therms, will better align the rates charged to the largest GS-1 customers with the rates charged to the Company's LV-1 Large Volume Firm Sales Service customers.**

A. The Company is proposing to modify the GS-1 rate structure – with specific attention to the largest customers in this rate class: (1) to better align the Company's rates with the costs to serve these customers, and (2) to align the rates charged to large GS-1 customers with the rates charged to LV-1 customers. The 50 largest GS-1 customers, with annual consumption between 98,000 and 541,000 therms, are similar to Rate LV-1 customers, which typically use between 200,000 therms and 500,000 annually. However, the 2015 average cost per therm to these large GS-1 customers, $0.7004 per therm,[13] was significantly greater than the 2015 average cost per therm to the Company's LV-1 customers, $0.4945 per therm. By adding a fourth block and setting the rate for monthly consumption in

[12] Service under the Company's Rate Schedule LV-1 is available to customers that use at least 200,000 therms annually.

[13] (1) Actual 2015 billing system revenues from all customers with annual usage of at 100,000 therms was $4,540,601; (2) Annual 2015 billing system usage from all customers with annual usage of at least 100,000 therms was 6,482,602; (3) $4,540,601 / 6,482,602 = $0.7004.

the fourth block at an appropriate level, the Company's proposed modification to the GS-1 rate structure will address the significant difference between rates charged to large GS-1 customers and rates charged to the Company's LV-1 customers.

**D. Elimination of Seasonal Rates**

**Q. Please describe and explain the Company's current Rate Schedules that charge different rates for gas service in the summer and winter.**

A. A list of the current rate schedules with rates that differ by season are listed in Table B.8, below.

**Table B.8 Intermountain Rate Schedules with Seasonal Rate Structures**

| Rate Schedule | |
|---|---|
| RS-1 | Residential Service |
| RS-2 | Residential Service- Space and Water Heating |
| GS-1 | General Service |
| IS-R | Residential Interruptible Snowmelt Service |
| IS-C | Small Commercial Interruptible Snowmelt Service |

For the Rate Schedules listed in Table 8, the customer charges and the per therm charges for winter months (billing periods ending December through March) are less than the customer charges and the per therm charges for summer months (billing periods ending April through November).

The rates charged to customers in Industrial Rate Schedules LV-1 (Large Volume Firm Sales Service), T-3 (Interruptible Distribution Transportation Service), T-4 (Firm Distribution Only Transportation Service), and T-5 (Firm Distribution Service with Maximum Daily Demands) are the same throughout the year; the rates do not vary by season.

**Q. Please explain why the Company is proposing to eliminate rate structures with seasonal rates that are lower for gas service during winter months and higher for gas usage in summer months.**

A. The Company is proposing to eliminate seasonal rates because there is no cost justification to continue the current seasonal rate structures. The results of the Company's ACOSS are not developed or reported by season.

**Q. Are you aware of any gas distribution companies that have rate structures with seasonal rates that are lower for gas service during winter months and higher for gas usage in summer months?**

A. No, I am not. I reviewed the tariffs of Avista Idaho and gas distribution companies in surrounding states[14] and I determined that, other than Intermountain Gas, no gas distribution company has rates that are different by season.

**E. Cost Based Customer Charges**

**Q. Please summarize the testimony of Company Witness Terzic that addresses cost-based customer charges.**

A. To summarize the points that Mr. Terzic makes in his testimony concerning customer charges, Mr. Terzic recommends that Residential RS and General Service GS-1 customer charges should be increased (1) to match the Company's costs, which are largely fixed, from year to year with the Company's distribution service revenues; (2) to make the Company's rates to these classes better reflect the unit customer-related costs to serve customers in these classes.

**Q. Please provide the current RS-1, RS-2 and GS-1 customer charges.**

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[14] I reviewed the tariffs of the following gas distribution companies: Avista Utilities (Idaho), MDU (Montana), Avista Utilities (Oregon), Cascade Natural Gas Corporation (Oregon), Cascade Natural Gas Corporation (Washington), Avista Utilities (Washington).

A. I have prepared Table B.9, below, to show the current customer charges. To demonstrate the large differences between the current Residential and General Service customer charges and costs to serve, I have also included in Table B.9 the unit customer-related costs as determined in Exhibit INT-20: Class Cost of Service Summary Results.

**Table B.9 Customer Charges and Unit customer-related ACOSS Results**

| Customer Charge per bill | RS-1 | RS-2 | IS-R | GS-1 | IS-C |
|---|---|---|---|---|---|
| Summer | $2.50 | $2.50 | $2.50 | $2.00 | $2.00 |
| Winter | $6.50 | $6.50 | $6.50 | $9.50 | $9.50 |
| | | | | | |
| ACOSS | $13.61 | $13.61 | $13.61 | $46.85 | $46.85 |

The Company's proposed rates, which are described in the following Section IV.F of my testimony, reduces the significant gap between the current customer charges and the unit customer-related costs.

**F. Proposed Large Industrial Firm Transportation Rate Schedule**

**Q. Please summarize the Company's proposal relating to current Rate Schedules T-4 and T-5.**

A. As described and supported in the testimony of Company Witness Swenson, the Company is proposing to combine Rate Schedules T-4 and T-5, and to charge one set of rates to all customers in this new rate classification.

As I explain in Section IV.H, Rate Design, to design the single set of rates for the new Rate Schedule T-4, I used the ACOSS results for the new Rate T-4 and the combined billing determinants of current T-4 and T-5 customers, accounting for customer migration.

**G. Cost-based Demand Charges**

**Q. Please summarize the testimony of Company Witness Terzic that addresses cost-based demand charges.**

A. To summarize the points that Mr. Terzic makes in his testimony concerning demand charges for large industrial customers, Mr. Terzic recommends that demand charges should be implemented for Intermountain's large industrial firm service rate classes because customers' demand (as measured by daily consumption) is closely related to the required capacity of the distribution system, and the capital investment in that distribution system.

**Q. Please describe how you designed the proposed demand charges for Industrial customers.**

A. The Company plans to implement demand charges for Rate Schedules LV-1 and Rate Schedule T-4. As explained in the testimony of Mr. Swenson, the Company has worked with customers in these classes to determine levels of contract demand that appropriately reflect the capacity that the Company must have available, to provide firm reliable service to each of these customers. I designed the Rate Schedule LV-1 and T-4 demand charges to recover a large proportion of the respective class distribution margin revenue requirement at equal rates of return. I designed commodity (per therm) charges for these classes to recover the smaller portion of the class distribution margin revenue requirement at equal rates of return that was not recovered by the demand charges that I designed.

## H. Rate Design

### 1. Introduction

**Q. Please describe the principles that you followed in designing the Company's proposed base rates.**

A. I developed the proposed rates to be consistent with what I am told are the Commission's long standing rate structure goals of setting rates based primarily on cost of service, and minimizing inter and intra class subsidies. I was also generally guided by Bonbright's rate design principles, and especially Mr. Bonbright's objectives that utility rate structures must be efficient, simple, and ensure continuity of rates, fairness between rate classes, and corporate earnings stability.

**Q. Please explain your understanding of these principles.**

A. An efficient rate structure promotes economically justified use of the Company's sales and distribution services, and discourages wasteful use. Rate design simplicity is achieved if the customers understand what they are being charged, *i.e.,* the level of rates and the rate structure. Rate continuity requires that changes to the rate structure should be gradual allowing customers to modify their usage patterns over time. A rate design is fair if no customer class pays more than the costs to serve that class. A rate design provides for earnings stability if the Company has a reasonable opportunity to earn its allowed rate of return during the time that the rates are in effect.

**Q. Have you prepared a schedule that shows how you calculated the proposed rates?**

A. Yes, I have prepared Exhibit 24 to show the analysis and calculations that I used to determine the final proposed base rates. Exhibit 24 is organized into the following sections that are related to steps in the rate design process.

- Section A shows proforma test year normalized calendar month revenue detail.
- Section B shows billing determinant detail.
- Section C shows the development of class revenue targets.
- Section D shows the development of the proposed rates.

In each section, columns A through F show data and calculations by rate class and totals. I have also provided a detailed line-by-line explanation of the calculations in Column G.

### 1. Class Revenue Targets

**Q. What is the revenue requirement that you used for the purpose of designing rates?**

A. I designed the Company's base rates to recover distribution margin of $93,243,187 which is shown on Exhibit 20: Class Cost of Service Summary Results, Page 2, Line 13 Column (b), less Line 3 Column (b) and Exhibit 24 Column F, Line 55.

**Q. How did you assign the total distribution margin of $93,243,187 to each of the Company's rate classes?**

A. I determined class revenue targets based on the class revenue requirements at equal rates of return for each rate class[15] as determined in the ACOSS that I

[15] The ACOSS develops separate revenue requirements for each rate class, as shown in Exhibit 20.

prepared. As described above in this testimony, the ACOSS total base-revenue requirement for the Company is net of the costs recovered through Intermountain's purchased gas adjustment mechanism.

**2. Base Rate Calculations**

**Q. Please explain how you designed the Company's proposed base rates.**

A. To design base rates that would recover the class base revenue targets from the previous step, I followed the process that is described below:

a. I (i) determined the appropriate level of customer charges for Rate Schedules RS and GS-1 and (ii) calculated Customer Charge revenues for these classes

b. I (i) determined the appropriate level of demand charges for the Company's Industrial firm service Rate Schedules LV-1 and T-4 and (ii) calculated Demand Charge revenues for these classes

c. I determined the remaining Rate Schedule class revenue requirement to be recovered from volumetric rates in one of the following approaches:

1. For Rate Schedules RS and GS-1, I subtracted Customer Charge revenues from total Rate Schedule distribution margin revenue requirements

2. For Rate Schedules LV-1 and T-4, I subtracted Demand Charge Revenues from Rate Schedule distribution margin revenue requirements

3. For Rate Schedule T-3, the volumetric rates were designed to recover the total Rate Schedule class revenue requirement

d. I determined the appropriate commodity charges by block, for those Rate Structures with multiple rate blocks

e. I calculated revenues at final rates.

**Q. Please explain Step (a) in the rate design process, which you described as determining the appropriate level of customer charges and calculating Customer Charge revenues.**

A. To determine the appropriate level of customer charges for Rate Schedules RS and GS-1, I considered: (1) the customer-related rates and unit costs, which are summarized in Table B.9; in Section IV.E of this testimony, above and (2) Bonbright's rate design principles of rate continuity and customer impacts. As shown in Table B.9, the customer related costs for the Residential class are $13.61 per customer. However, to adhere to Bonbright's principles mentioned above, the Company is proposing a more gradual increase in the Residential customer charge to $10.00. The customer related costs for the GS-1 class are $45.85. Again, the Company is proposing a more gradual change of $35.00.

**Q. Please explain the calculation of Rate Schedule RS and GS-1 class customer charge revenues and the class volumetric revenue target.**

A. I calculated class customer charge revenues by multiplying the proposed customer charges times the customer count billing determinants, which are shown in Exhibit 24, Line 12. To determine the commodity revenue targets for Rate Schedule RS and GS-1, (the remaining class revenue target to be recovered from volumetric rates to these classes), I subtracted the class customer charge revenues from the total class revenue target, shown on Exhibit 24, Line 65.

To the extent the Company's required revenue is not collected through the customer charge and the volumetric charge, the surplus or deficit will be trued up using the Company's proposed FCCM as described by Company Witness McGrath.

**Q. Please explain Step (b) in the rate design process, which you described as determining the appropriate level of demand charges for the Company's Industrial firm service rate classes and calculating Demand Charge revenues.**

A. I set the demand charges for Rate Schedules LV-1 and T-4 at levels that would recover a large portion of the class revenue requirement at equal rate of return. The demand charges of $0.30 per therm for LV-1 and T-4 are shown on Exhibit 24, Line 79, and the demand charge revenues are shown on Exhibit 24, Line 80.

**Q. Please explain Step (d) in the rate design process, which you described as determining the appropriate rates by block, for those Rate Structures with multiple rate blocks.**

A. As a preliminary matter, I determined that I would design the new fourth GS-1 rate block to apply to monthly usage of 10,000 therms or more, based on my review of GS-1 billing data. I then determined that I should set the commodity rate for that fourth block at $0.07500 per therm, to reduce the difference between bills at GS-1 rates to these customers and bills at LV-1 rates.

After I determined the appropriate Rate for the fourth block, Rate Schedule GS-1, I calculated volumetric rates for all other Rate Schedules, as shown on Exhibit 24, Lines 110 through and 118.

**Q. Please explain Step (e) in the rate design process, which you described as calculating revenues at final rates.**

A. Step (e) is simply the calculation of the revenues that the proposed rates would produce, based on rate case Billing Determinants. My calculations, which are presented in Exhibit 24 Lines 120 to 133, show that the proposed base rates produce total distribution margins of $93,244,715, which is greater than the base revenue requirement of $93,243,187 by $1,528. The difference is caused by rounding the proposed per therm rates to five significant digits and the proposed customer charges and demand charges to two significant digits.

### 3. Bill Impact Analysis

**Q. Have you prepared bill-impact analyses?**

A. Yes. An average RS-1 customer will see an annual increase of approximately $14.00 or 3% per year. Current RS-2 customers with average usage will experience an increase of $27.70 per year, or 5%. A GS customer with average usage will see an increase of 6% per year, or $145.90.

**Q. Does this conclude your testimony on rate design?**

A. Yes, it does.